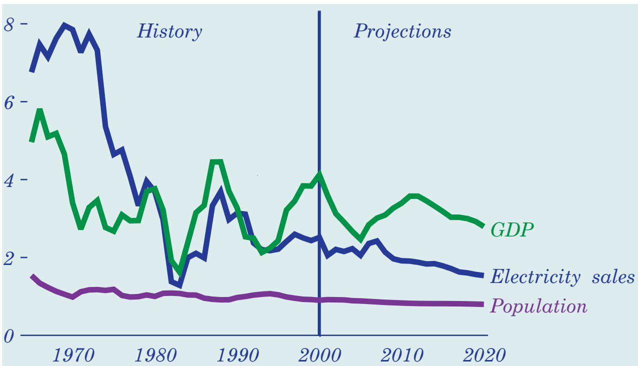
Electricity Use Is Expected To Grow More Slowly Than GDP

Figure 45. Population, gross domestic product, and electricity sales, 1965-2020 (5-year moving average annual percent growth)



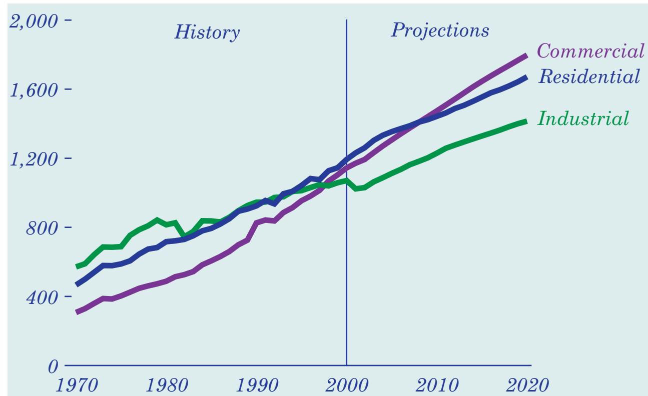
As generators and cogenerators try to adjust to the evolving structure of the electricity market, they also face slower growth in demand than in the past. Historically, the demand for electricity has been related to economic growth. That positive relationship is expected to continue, but the ratio is uncertain.

During the 1960s, electricity demand grew by more than 7 percent per year, nearly twice the rate of economic growth (Figure 45). In the 1970s and 1980s, however, the ratio of electricity demand growth to economic growth declined to 1.5 and 1.0, respectively. Several factors have contributed to this trend, including increased market saturation of electric appliances, improvements in equipment efficiency and utility investments in demand-side management programs, and more stringent equipment efficiency standards. Throughout the forecast, growth in demand for office equipment and personal computers, among other equipment, is dampened by slowing growth or reductions in demand for space heating and cooling, refrigeration, water heating, and lighting. The continuing saturation of electric appliances, the availability and adoption of more efficient equipment, and efficiency standards are expected to hold the growth in electricity sales to an average of 1.8 percent per year between 2000 and 2020, compared with 3.0-percent annual growth in GDP.

Changing consumer markets could mitigate the slowing of electricity demand growth seen in these projections. New electric appliances are introduced frequently. If new uses of electricity are more substantial than currently expected, they could offset future efficiency gains to some extent.

Continued Growth in Electricity Use Is Expected in All Sectors

Figure 46. Annual electricity sales by sector, 1970-2020 (billion kilowatthours)



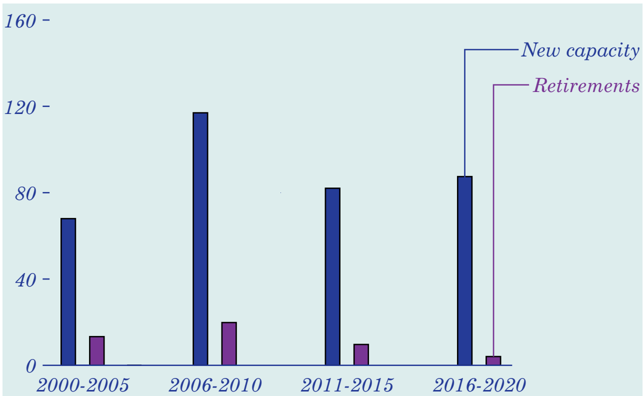
With the number of U.S. households projected to rise by 1.0 percent per year between 2000 and 2020, residential demand for electricity is expected to grow by 1.7 percent annually (Figure 46). Residential electricity demand changes as a function of the time of day, week, or year. During summer, residential demand peaks in the late afternoon and evening, when household cooling and lighting needs are highest. This periodicity increases the peak-to-average load ratio for local utilities, which rely on quick-starting gas turbines or internal combustion engines to meet peak demand. Although some regions now have surplus baseload capacity, growth in the residential sector is expected to create a need for more "peaking" capacity. Excluding cogeneration, peaking capacity from natural gas turbines and internal combustion engines is projected to increase from 78 gigawatts in 2000 to 178 gigawatts in 2020.

Electricity demand in the commercial and industrial sectors is projected to grow by 2.3 and 1.4 percent per year, respectively, between 2000 and 2020. Projected growth in commercial floorspace of 1.7 percent per year and growth in industrial output of 2.6 percent per year contribute to the expected increase.

In addition to sectoral sales, cogenerators in 2000 produced 147 billion kilowatthours for their own use in industrial and commercial processes, such as petroleum refining and paper manufacturing. By 2020, cogenerators are expected to see only a slight increase in their share of total generation, increasing their own-use generation to 228 billion kilowatthours as the demand for manufactured products increases.

Retirements and Rising Demand Are Expected To Require New Capacity

Figure 47. Projected new generating capacity and retirements, 2000-2020 (gigawatts)



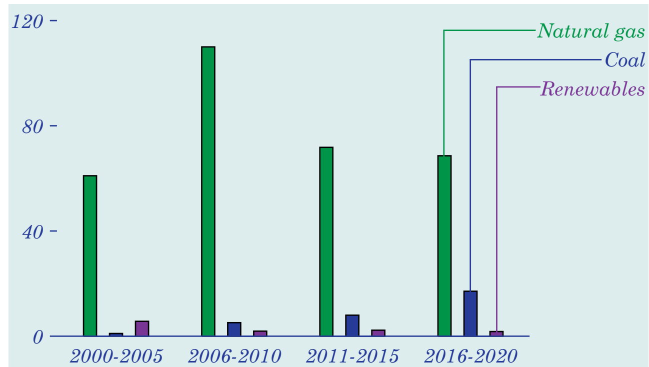
From 2000 to 2020, 355 gigawatts of new generating capacity (excluding cogenerators) is expected to be needed to meet growing demand and to replace retiring units (Figure 47). Between 2000 and 2020, 10 gigawatts (10 percent) of current nuclear capacity and 37 gigawatts (7 percent) of current fossil-fueled capacity [*85*] are expected to be retired, including 20 gigawatts of oil- and natural-gas-fired steam plants, nearly all before 2010. Of the 185 gigawatts of new capacity expected by 2010, 10 percent is projected to replace retired oil- and natural-gas-fired steam capacity.

Because of their favorable economics, combined-cycle units are projected to be used for most new baseload requirements. Efficiencies for combined-cycle units are expected to approach 54 percent by 2010, compared with 49 percent for coal-steam units, and the expected construction costs for combined-cycle units are only about 44 percent of those for coal-steam plants. As a result, most (59 percent) of the projected combined-cycle additions are expected before 2010. As natural gas prices rise later in the forecast, new coal-fired capacity is projected to become more competitive, and 80 percent of the projected additions of new coal-fired capacity are expected to be brought on line from 2010 to 2020.

As older nuclear power plants age and their operating costs rise, 10 percent of currently operating nuclear capacity is expected to be retired by 2020. More optimistic assumptions about operating costs for existing nuclear units would reduce the projected need for new fossil-based capacity and reduce fossil fuel prices.

Natural Gas Units Are Expected To Dominate New Capacity Additions

Figure 48. Projected electricity generation capacity additions by fuel type, including cogeneration, 2000-2020 (gigawatts)

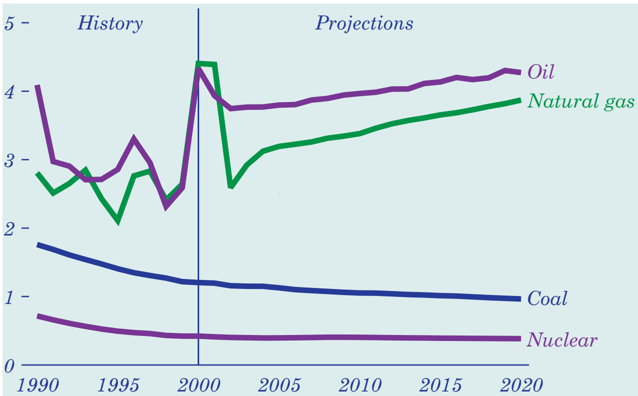


Before building new capacity, electricity generators are expected to use other options to meet demand growth—maintenance of existing plants, power imports from Canada and Mexico, and purchases from cogenerators. Even so, a total of 355 gigawatts of capacity (excluding cogenerators) is projected to be needed by 2020 to meet growing demand and to offset retirements. Of this new capacity, 88 percent is projected to be combined-cycle or combustion turbine technology, including distributed generation capacity, fueled by natural gas (Figure 48). Both technologies are designed primarily to supply peak and intermediate capacity, but combined-cycle technology can also be used to meet baseload requirements.

A total of 31 gigawatts of new coal-fired capacity is projected to come on line between 2000 and 2020, accounting for almost 9 percent of all the capacity expansion expected. Competition with low-cost gas-turbine-based technologies and the development of more efficient coal gasification systems have compelled vendors to standardize designs for coal-fired plants in efforts to reduce capital and operating costs in order to maintain a share of the market. Renewable technologies account for 3 percent of expected capacity expansion by 2020—primarily wind, geothermal, and municipal solid waste units. About 19 gigawatts of distributed generation capacity is projected to be added by 2020, as well as a small amount (less than 1 gigawatt) of fuel cell capacity. Oil-fired steam plants, with higher fuel costs and lower efficiencies, are expected to account for very little of the new capacity in the forecast.

Rising Natural Gas Prices, Falling Coal Prices Are Projected

Figure 49. Fuel prices to electricity generators, 1990-2020 (2000 dollars per million Btu)

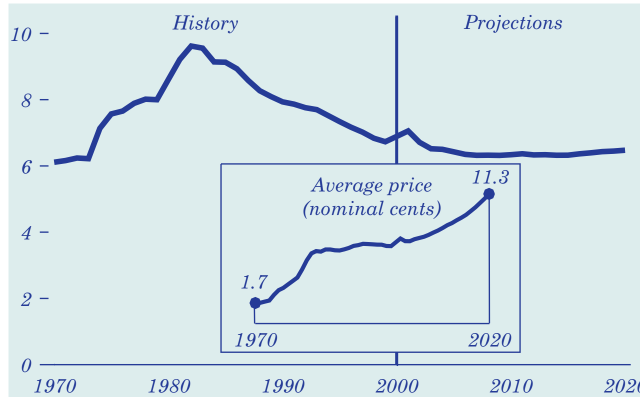


The cost of producing electricity is a function of fuel costs, operating and maintenance costs, and the cost of capital. In 2000, fuel costs typically represented $22 million annually—or 76 percent of the total operational costs (fuel and variable operating and maintenance)—for a 300-megawatt coal-fired unit, and $66 million annually—or 93 percent of the total operational costs—for a natural-gas-fired combined-cycle unit of the same size. For nuclear units, fuel costs are typically a much smaller portion of total production costs. Nonfuel operations and maintenance costs are a larger component of the operating costs for nuclear power units than for plants that use fossil fuels.

The impact of volatile natural gas prices in the forecast is more than offset by a combination of falling coal prices and stable nuclear fuel costs. After the price spikes of 2000 and 2001, natural gas prices to electricity suppliers are projected to rise by 2.2 percent per year in the forecast, from $2.64 per thousand cubic feet in 2002 to $3.94 in 2020 (Figure 49). The increases after 2002 are offset by forecasts of declining coal prices, declining capital expenditures, and improved efficiencies for new plants. Sufficient supplies of uranium and fuel processing services are expected to keep nuclear fuel costs around $0.40 per million Btu (roughly 4 mills per kilowatthour) through 2020. Oil prices to utilities are expected to increase by 0.7 percent per year after 2002, leading to a 59-percent decline in oil-fired generation (excluding cogeneration) between 2000 and 2020. Oil currently accounts for only 3 percent of total generation, however, and that share is expected to decline to 1 percent by 2020 as oil-fired steam generators are replaced by gas turbine technologies.

Average U.S. Electricity Prices Are Expected To Decline

Figure 50. Average U.S. retail electricity prices, 1970-2020 (2000 cents per kilowatthour)



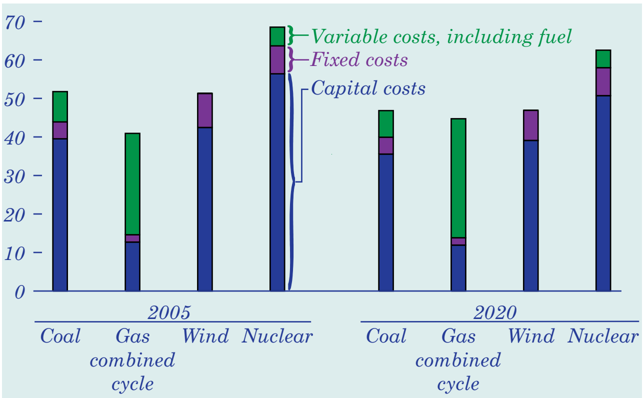
Between 2000 and 2020, the average price of electricity in real 2000 dollars is projected to decline by an average of 0.3 percent per year as a result of competition among electricity suppliers (Figure 50). By sector, projected prices in 2020 are 7, 8, and 3 percent lower than 2000 prices for residential, commercial, and industrial customers, respectively.

Before 2001, 14 States, including California, instituted competition in their retail electricity markets. Both the District of Columbia and Ohio began retail competition in 2001, and Texas and Virginia are scheduled to begin in 2002. Since the beginning of 2000, however, 7 States have delayed the opening of competitive retail markets beyond the dates originally planned, and in fall 2001 California suspended retail competition (see "Legislation and Regulations," pages 11-13).

Specific restructuring plans differ from State to State and utility to utility, but most call for a transition period during which customer access will be phased in. The transition period reflects the time needed for the establishment of competitive market institutions and the recovery of stranded costs as permitted by regulators. It is assumed that competition will be phased in over 10 years, starting from the inception of restructuring in each region. In all the competitively priced regions, the generation price is set by the marginal cost of generation. Transmission and distribution prices are assumed to remain regulated.

Least Expensive Technology Options Are Likely Choices for New Capacity

Figure 51. Projected levelized electricity generation costs, 2005 and 2020 (2000 mills per kilowatthour)



Technology choices for new generating capacity are made to minimize cost while meeting local and Federal emissions constraints. The choice of technology for capacity additions is based on the least expensive option available (Figure 51). The reference case assumes a capital recovery period of 20 years. In addition, the cost of capital is based on competitive market rates, to account for the competitive risk of siting new units.

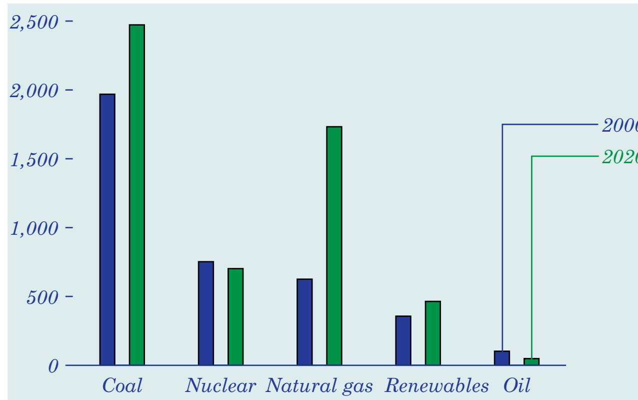
The costs and performance characteristics for new plants are expected to improve over time, at rates that depend on the current stage of development for each technology. For the newest technologies, capital costs are initially adjusted upward to reflect the optimism inherent in early estimates of project costs. As project developers gain experience, the costs are assumed to decline. The decline continues at a slower rate as more units are built. The performance (efficiency) of new plants is also assumed to improve, with heat rates declining by 4 to 13 percent between 2000 and 2010, depending on the technology (Table 9). No further improvement is expected after 2010.

Table 9. Costs of producing electricity from new plants, 2005 and 2020

Costs	2005 Advanced coal	2005 Advanced combined cycle	2020 Advanced coal	2020 Advanced combined cycle
	2000 mills per kilowatthour			
Capital	39.51	12.71	35.55	11.92
Fixed	4.39	1.90	4.39	1.90
Variable	7.87	26.31	6.89	30.90
Total	**51.77**	**40.92**	**46.83**	**44.72**
	Btu per kilowatthour			
Heat rate	7,469	6,639	6,968	6,350

Gas- and Coal-Fired Generation Grows as Nuclear Plants Are Retired

Figure 52. Projected electricity generation by fuel, 2000 and 2020 (billion kilowatthours)



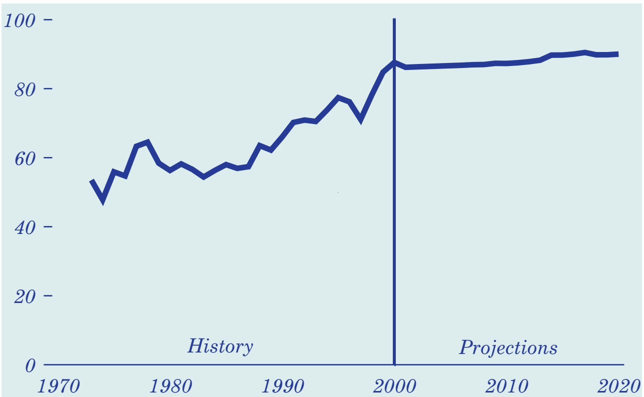
As they have since early in this century, coal-fired power plants are expected to remain the key source of electricity through 2020 (Figure 52). In 2000, coal accounted for 1,968 billion kilowatthours or 52 percent of total generation, including cogeneration. Although coal-fired generation is projected to increase to 2,472 billion kilowatthours in 2020, increasing gas-fired generation is expected to reduce coal's share to 46 percent. Concerns about the environmental impacts of coal plants, their relatively long construction lead times, and the availability of economical natural gas make it unlikely that many new coal plants will be built before about 2005. Nevertheless, slow growth in other generating capacity, the huge investment in existing plants, and increasing utilization of those plants are expected to keep coal in its dominant position. By 2020, it is projected that 23 gigawatts of coal-fired capacity will be retrofitted with scrubbers to meet the requirements of the Clean Air Act Amendments of 1990 (CAAA90).

Investment in existing plants is expected to make nuclear power a growing source of electricity at least through 2001. As a result of recent improvements in the performance of nuclear power plants, nuclear generation is projected to remain at current levels until 2006, then decline as older units are retired.

In percentage terms, natural-gas-fired generation is projected to show the largest increase, from 16 percent of the total in 2000 to 32 percent in 2020. As a result, by 2004, natural gas is expected to overtake nuclear power as the Nation's second-largest source of electricity. Generation from oil-fired plants is projected to remain fairly small throughout the forecast.

Nuclear Power Plant Operating Performance Is Expected To Improve

Figure 53. Nuclear power plant capacity factors, 1973-2020 (percent)



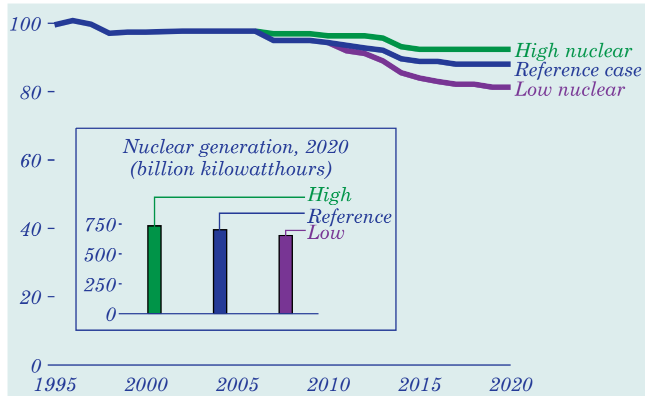
The United States currently has 104 operable nuclear units, which provided 20 percent of total electricity generation in 2000. The performance of U.S. nuclear units has improved in recent years, to a national average capacity factor of 88 percent in 2000 (Figure 53). It is assumed that performance improvements will continue, to an expected average capacity factor of 90 percent by 2015.

In the reference case, 10 percent of current nuclear capacity is projected to be taken out of service by 2020, primarily as a result of the high costs of maintaining the performance of older nuclear units as compared with the cost of constructing the least expensive alternative. No new nuclear units are expected to become operable between 2000 and 2020, because natural gas and coal-fired units are projected to be more economical.

Nuclear units are projected to be retired when their operation is no longer economical relative to the cost of building replacement capacity. As a result, their operational lifetimes could be either shorter or longer than their current operating licenses. As of October 2001, license renewals for 6 nuclear units had been approved by the U.S. Nuclear Regulatory Commission, and 14 other applications were being reviewed. As many as 24 other applicants have announced intentions to pursue license renewals over the next 5 years, indicating a strong interest in maintaining the existing stock of nuclear plants. In addition, the Bush Administration's National Energy Policy Plan (NEPP) recommends support for the expansion of U.S. nuclear generating capability (see "Legislation and Regulations," pages 17-21).

Nuclear Power Could Be Key to Reducing Carbon Dioxide Emissions

Figure 54. Projected operable nuclear capacity in three cases, 1995-2020 (gigawatts)

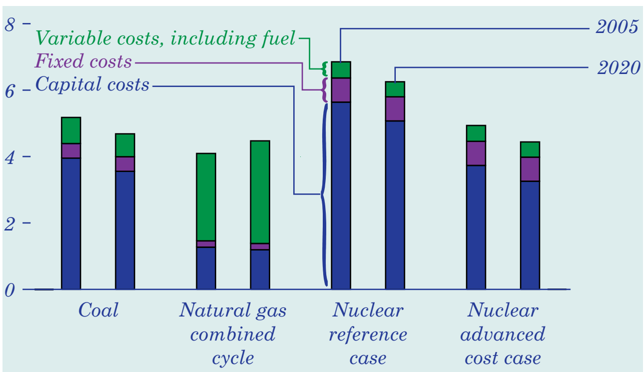


Two alternative cases—the high and low nuclear cases—show how nuclear plant retirement decisions affect the projections for capacity (Figure 54). In the high nuclear case, which assumes that no aging-related capital expenditures will be required, fewer retirements of existing nuclear units are projected before 2020 than in the reference case. Conditions favoring continued operation of existing units could include performance improvements, a solution to the waste disposal problem, and stricter limits on emissions from fossil-fired generating facilities. The low nuclear case assumes that the capital expenditures required for continued operation are higher than assumed in the reference case, leading to the projected retirements of 9 additional units by 2020. Higher costs could result from more severe degradation of the units or from waste disposal problems.

In the high nuclear case it is projected that 5 gigawatts of new fossil-fired capacity would not be needed, as compared with the reference case, and carbon dioxide emissions are projected to be 3 million metric tons carbon equivalent lower in 2020 than projected in the reference case. In the low nuclear case, 8 gigawatts of new fossil-fired capacity is projected to be built to replace additional retiring nuclear units beyond those projected to be retired in the reference case. The additional new capacity is projected to be made up predominantly of natural-gas-fired units (63 percent) and coal-fired units (37 percent). The additional fossil-fueled capacity is projected to increase carbon dioxide emissions in 2020 by 1 percent above the reference case projection.

Sensitivity Case Looks at Possible Reductions in Nuclear Power Costs

Figure 55. Projected electricity generation costs by fuel type in the advanced nuclear cost case, 2005 and 2020 (2000 cents per kilowatthour)

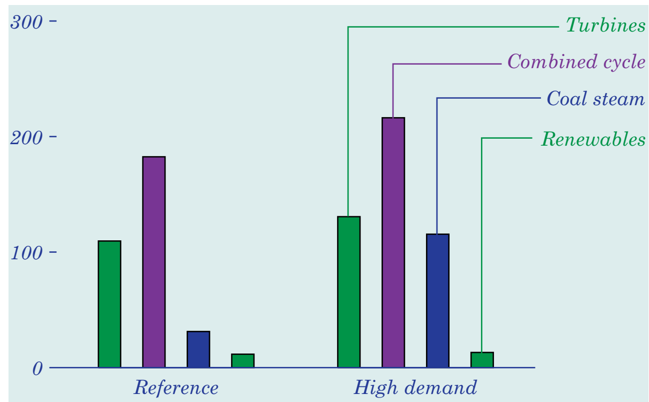


The *AEO2002* reference case assumptions for the cost and performance characteristics of new technologies are based on current estimates by government and industry analysts, allowing for uncertainties about new, unproven designs. The cost assumptions are based on the Westinghouse AP600 advanced passive reactor design. For nuclear power plants, an advanced nuclear cost case analyzes the sensitivity of the projections to lower costs and construction times for new plants. The more optimistic cost assumptions for the advanced cost case are consistent with goals endorsed by DOE's Office of Nuclear Energy, including progressively lower overnight construction costs—by 23 percent initially compared with the reference case and by 33 percent in 2020—and shorter lead times. The advanced case assumes a 3-year lead time, which is a goal of the Office of Nuclear Energy. Cost and performance characteristics for all other technologies are assumed to be the same as those in the reference case.

Projected nuclear generating costs in 2020 in the advanced cost case are competitive with the generating costs for new coal- and natural-gas-fired units (Figure 55). A total of 940 megawatts of advanced nuclear capacity is projected to come on line by 2020 in the advanced nuclear cost case. The projections in Figure 55 are average generating costs, assuming generation at the maximum capacity factor for each technology; the costs and relative competitiveness of the technologies could vary across regions. If non-baseload generation is needed, capital-intensive coal and nuclear generating technologies operating at lower capacity factors would be less competitive.

High Demand Assumption Leads to Higher Fuel Prices for Generators

Figure 56. Projected cumulative new generating capacity by type in two cases, 2000-2020 (gigawatts)

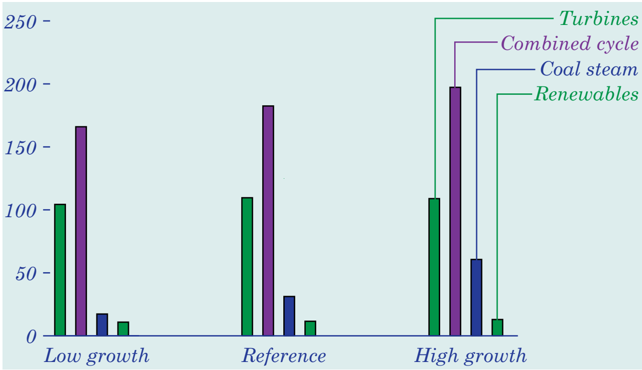


Electricity consumption grows in the forecast, but the projected rate of increase is less than historical levels as a result of assumptions about improvements in end-use efficiency, demand-side management programs, and population and economic growth. Different assumptions result in substantial changes in the projections. In a high demand case, electricity demand is assumed to grow by 2.5 percent per year between 2000 and 2020, as compared with the growth rate of 2.2 percent per year between 1990 and 1999. In the reference case, electricity demand is projected to grow by 1.8 percent per year.

In the high demand case, 147 gigawatts more new generating capacity, excluding cogenerators, is projected to be built between 2000 and 2020 than in the reference case (Figure 56). The shares of coal- and natural-gas-fired capacity additions (including non-coal steam, combustion turbine, combined cycle, distributed generation, and fuel cell) are projected to be 23 percent and 74 percent, respectively, in the high demand case, compared with 9 and 88 percent in the reference case. Coal consumption is projected to be 19 percent higher in the high demand case than in the reference case, natural gas consumption 6 percent higher, and carbon dioxide emissions 17 percent (131 million metric tons carbon equivalent) higher. More rapid assumed growth in electricity demand also leads to higher projected prices for electricity in 2020, averaging 6.6 cents per kilowatthour in the high demand case, compared with 6.5 cents in the reference case. Higher projected fuel prices, especially for natural gas, are the primary reason for the difference in electricity prices.

Rapid Economic Growth Would Boost Advanced Coal-Fired Capacity

Figure 57. Projected cumulative new generating capacity by technology type in three economic growth cases, 2000-2020 (gigawatts)



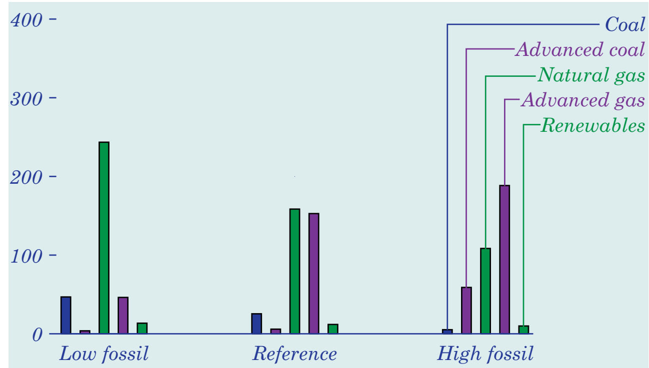
The projected annual average growth rate for GDP from 2000 to 2020 ranges from 3.4 percent in the high economic growth case to 2.4 percent in the low economic growth case. The difference leads to a 10-percent change in projected electricity demand in 2020, with a corresponding difference of 88 gigawatts (excluding cogenerators) in the amount of new capacity projected to be built in the high and low economic growth cases. In the high economic growth case, generators are expected to retire about 6 percent of their current capacity by 2020 as the result of increased operating costs for aging units.

Much of the new capacity projected to be needed in the high economic growth case beyond that added in the reference case is expected to consist of new coal-fired plants, which make up 62 percent of the projected additional new capacity in the high growth case. The stronger assumed growth also is projected to stimulate additions of natural-gas-fired plants, accounting for 35 percent of the projected capacity increase in the high economic growth case over that projected in the reference case (Figure 57).

Current construction costs for a typical plant range from $456 per kilowatt for combined-cycle technologies to $1,338 per kilowatt for coal-steam technologies. Those costs, along with the difficulty of obtaining permits and developing new generating sites, make refurbishment of existing power plants a profitable option. Between 2000 and 2020, generators are expected to maintain most of their older coal-fired plants while retiring many older, higher cost oil- and natural-gas-fired steam generating plants.

Gas-Fired Technologies Lead New Additions of Generating Capacity

Figure 58. Projected cumulative new generating capacity by technology type in three fossil fuel technology cases, 2000-2020 (gigawatts)

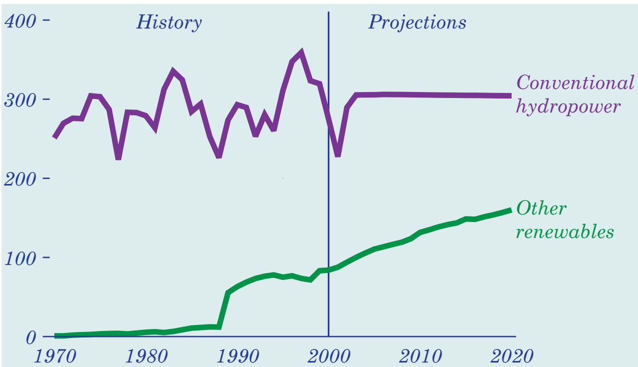


The *AEO2002* reference case uses the cost and performance characteristics of generating technologies to select the mix and amounts of new generating capacity for each year in the forecast. Numerical values for the characteristics of different technologies are determined in consultation with industry and government specialists. In the high fossil fuel case, capital costs and/or heat rates for advanced fossil-fired generating technologies (integrated coal gasification combined cycle, advanced combined cycle, and advanced combustion turbine) reflect potential improvements in costs and efficiencies as a result of accelerated research and development. The low fossil fuel case assumes that capital costs and heat rates for advanced technologies will remain flat throughout the forecast at 2002 levels.

The projected share of additions accounted for by natural gas technologies varies from 80 percent to 88 percent across the cases, and the projected mix between current and advanced gas technologies varies significantly (Figure 58). In the low fossil fuel case 16 percent (46 gigawatts) of the gas plants projected to be added are advanced technology facilities, as compared with 63 percent (188 gigawatts) in the high fossil fuel case. Coal-fired capacity makes up a higher share of projected additions in both the low and high fossil fuel cases (14 percent and 17 percent) than in the reference case (9 percent). In the low case, conventional coal-fired generating capacity is more competitive with new natural-gas-fired capacity because no improvement is assumed for advanced natural gas technologies. In the high case, advanced coal technologies are more competitive as a result of the assumed rapid pace of technology improvements.

Increases in Nonhydropower Renewable Generation Are Expected

Figure 59. Grid-connected electricity generation from renewable energy sources, 1970-2020 (billion kilowatthours)

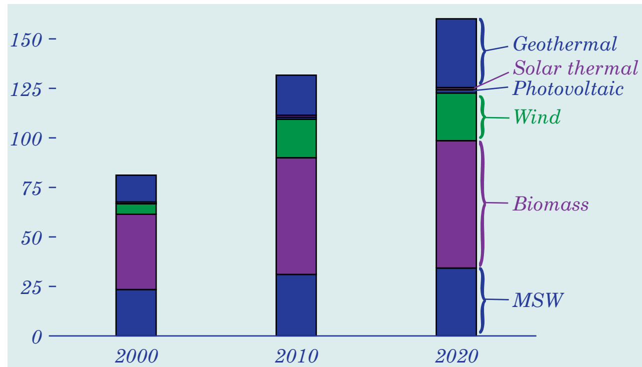


In the *AEO2002* reference case, despite improvements and incentives, grid-connected generators (including cogenerators and distributed generation) that use renewable fuels are projected to remain minor contributors to U.S. electricity supply, increasing from 357 billion kilowatthours of generation in 2000 (9 percent of the total, including cogeneration and distributed generation) to 464 billion (9 percent) in 2020. Lower than normal precipitation in 2000 reduced hydroelectric generation to 276 billion kilowatthours, from 316 billion in 1999. Despite the addition of 610 megawatts of new capacity by 2020, environmental and other requirements are projected to limit conventional hydroelectric generation to 304 billion kilowatthours in 2020, or 6 percent of total electricity supply (Figure 59).

Nonhydroelectric renewables account for 4 percent of projected additions to generating capacity from 2000 to 2020. Generation from nonhydropower renewable energy sources is projected to increase from 81 billion kilowatthours in 2000 (2 percent of both total generation and electricity sales) to 160 billion in 2020 (3 percent of total generation and electricity sales). The largest source of nonhydroelectric renewable generation in the forecast is biomass, including cogeneration and co-firing in coal-fired power plants. Electricity generation from biomass is projected to increase from 38 billion kilowatthours in 2000 to 64 billion kilowatthours (1 percent of total electricity supply) in 2020. Most of the increase (74 percent) is expected to come from cogenerators and a smaller amount from co-firing. Few new dedicated biomass plants are expected to be built.

Biomass and Geothermal Lead Growth in Nonhydro Renewables

Figure 60. Projected nonhydroelectric renewable electricity generation by energy source, 2010 and 2020 (billion kilowatthours)



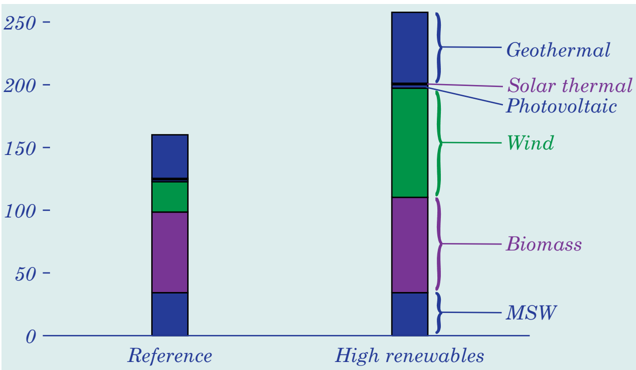
In addition to biomass, significant increases are projected for both geothermal energy and wind power capacity from 2000 to 2020 (Figure 60). High-output geothermal capacity increases by 87 percent in the forecast, to 5 gigawatts, and is projected to provide 35 billion kilowatthours of electricity generation (1 percent of total electricity supply) in 2020. The expansion of geothermal capacity is dependent on the success of several new, untested sites. Wind capacity increases by nearly 300 percent, to 4 gigawatts in 2001 and 9 gigawatts in 2020; and generation from wind plants, many of which are expected to be built in response to State mandates, is projected to increase from 5 billion kilowatthours in 2000 to 24 billion kilowatthours (less than 1 percent of total electricity supply) in 2020. The prospects for wind power are dependent on cost, performance, State and Federal incentives, and environmental preferences.

Electricity generation from municipal solid waste, including both direct firing with solid waste and the use of landfill gas, is projected to increase by 11 billion kilowatthours from 2000 to 2020. No new capacity additions are expected for plants that burn solid waste, but landfill gas capacity is projected to grow by more than 1 gigawatt.

Solar technologies are not expected to make significant contributions to U.S. electricity supplies through 2020. In total, central-station photovoltaic capacity and other grid-connected solar generators at end-use sites are projected to provide 0.05 percent of total electricity generation in 2020 [*86*].

Wind Energy Use Could Gain Most From Cost Reductions

Figure 61. Projected nonhydroelectric renewable electricity generation by energy source in two cases, 2020 (billion kilowatthours)

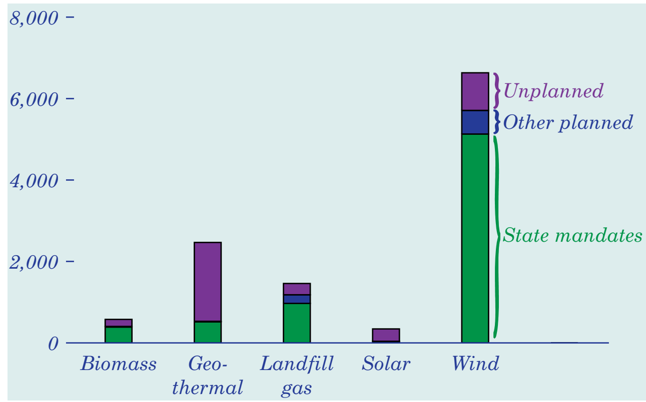


The high renewables case assumes more favorable characteristics for nonhydroelectric renewable energy technologies than in the reference case, including lower capital costs, higher capacity factors, and lower operating costs for some technologies [*87*]. The assumptions in the high renewables case approximate the renewable energy technology goals of the U.S. Department of Energy. Fossil and nuclear technology assumptions are not changed from those in the reference case.

More rapid technology improvements are projected to increase renewable energy use in the high renewables case, but the predominant role of fossil-fueled technologies in U.S. electricity supply does not change. Total generation from nonhydroelectric renewables is projected to reach 258 billion kilowatthours in 2020, compared with 160 billion in the reference case (Figure 61), increasing from 3 percent of total generation to 5 percent. About 63 billion kilowatthours of the projected difference is generated from wind power, 22 billion kilowatthours from baseload geothermal, and 11 billion kilowatthours from industrial cogeneration using biomass. Central-station solar technologies remain too expensive for use in new capacity additions, but the use of small-scale photovoltaics in end-use markets is expected to be slightly higher than in the reference case. The projected increase in renewable energy use in the high renewables case reduces fossil fuel use relative to the reference case projection, lowering total projected carbon dioxide emissions by 18 million metric tons carbon equivalent (1 percent).

State Mandates Call for More Generation From Renewable Energy

Figure 62. Projected additions of renewable generating capacity, 2001-2020 (megawatts)



For *AEO2002* it is assumed that State mandates will require total additions of 7,035 megawatts of central-station renewable generating capacity from 2001 through 2020, including 5,129 megawatts of wind capacity, 969 megawatts of landfill gas capacity, 390 megawatts of biomass capacity, 516 megawatts of geothermal capacity, and 31 megawatts of solar (photovoltaic and thermal) capacity (Figure 62).

Estimates available from State implementation plans include new renewable energy capacity resulting from commercial builds, renewable portfolio standards, systems benefits charges, and other mandates. States with renewable fuel mandates or renewable portfolio standards that project significant capacity additions include Texas (2,279 megawatts), California (1,930 megawatts), Nevada (1,148 megawatts), and New Jersey (904 megawatts). Smaller amounts are projected for Massachusetts, Minnesota, Iowa, Wisconsin, and Arizona. The reference case assumes that 3,828 megawatts of new wind capacity required by State mandates after 2002 will be built; however, expectations for wind power are clouded by the current uncertainty about extension of the Federal production tax credit for renewable electricity generation, which expires at the end of 2001 [*88*]. The tax credit, applied to electricity produced from new renewable generators using wind or closed-loop biomass energy for 10 years after the facility has been placed in service, currently is worth 1.7 cents per kilowatthour. (Closed-loop biomass plants use energy crops grown specifically for energy production.) For further discussion of the tax credit and the potential impacts of a 5-year extension, see "Legislation and Regulations," page 14.